U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/85-35; 50-388/85-31

Docket Nos. 50-387 (CAT C); 50-388 (CAT C)

License Nos. NPF-14; NPF-22

Licensee: Pennsylvania Power and Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: November 11, 1985 - December 15, 1985

Inspectors: R. H. Jacobs, Senior Resident Inspector
L. R. Plisco, Resident Inspector

Approved By: Jack Strosnider 1/3/86
J. Strosnider, Chief date
Reactor Projects Section 1B, DRP

Inspection Summary:

Areas Inspected: Routine resident inspection (U1 - 95 hours; U2 - 64 hours) of plant operations, licensee events, open items, surveillance, and maintenance.

Results: Review of the 18 Month Diesel Generator Inspection procedures found that all of the vendor recommendations are not included in the procedures (Detail 5.3.1); Review of other 18 Month Diesel Generator surveillance procedures identified several deficiencies (Detail 5.3.2); Review of bypasses identified discrepancies with administrative controls (Detail 1.7). No violations were identified.

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Inspector Followup Item (387/85-11-06; 388/85-11-06): Failure to Verify Those Valves Designated in the ISI Program as Rapid-Acting Met Specified Maximum Stroke Times

The inspector identified that the licensee failed to verify, during surveillance testing, that "rapid-acting" valves in the LPCI system met a specified maximum stroke time of short duration as required by the Pump and Valve Inservice Testing Program.

The licensee revised the applicable valve exercising procedures to ensure those valves designated as "rapid-acting" are timed to meet a maximum stroke time acceptance criteria. The inspector reviewed the Procedure Change Approval Forms (PCAF) for the applicable procedures and verified that the closure time acceptance criteria is now included.

1.2 (Closed) Violation (387/85-16-05): Missed Surveillances on ESW System

In April 1985, the licensee identified that three surveillances involving the ESW system were performed after the allowable surveillance interval. The ESW system is common to both units, and common systems are the responsibility of Unit 1 operators. Unit 1 was in an extensive outage during this period and these surveillances were not required to be performed until the completion of the Unit 1 outage. However, they were required to support Unit 2 operations although Unit 2 operators were not responsible for the surveillance performance. Hence, the cause of the missed surveillances was a lack of clear accountability for conduct of common system surveillances in support of Unit 2.

In the licensee's Notice of Violation response dated August 15, 1985, the licensee indicated that they had revised the Operations Weekly Surveillance Schedule format to include common system surveillances on both the Unit 1 and Unit 2 schedules. Common surveillances are also highlighted on the schedule by a different color and those that cannot be completed as scheduled appear as outstanding surveillances in a different section. Hence, both Unit's operators are responsible for the tracking and performance of common system surveillances. The PMIS "Daily Open Surveillance Report" also now includes violation dates for listed surveillances to enable late surveillances to be identified by managers and the surveillance program coordinator. The event was also reviewed by Operations Supervisory personnel. The inspector verified completion of the above actions.

1.3 (Closed) Inspector Followup Item (387/83-21-03): RCIC Condensate Pump Motor Breakdown

In July 1983, the RCIC barometric condenser condensate pump motor pump tripped while the RCIC system was running. The licensee's investigation found the event was caused by mechanical failure of the condensate pump motor commutator which occurred when solder was flung out of a commutator slot. The inspector questioned whether preventive maintenance checks should be performed more frequently to prevent future problems with the motor disabling the RCIC system.

Licensee discussions wih the pump motor vendor found that increased maintenance is not likely to reveal mechanical breakdown of the electrical connection in advance. The only indication may be discoloration of the commutator, which is inspected for in maintenance procedure MT-GE-002, "Brush, Commutator and Slip Ring Inspection." This inspection is performed every six years and is scheduled for completion in July 1986. Originally, it was thought that this failure may be associated with excessive DC voltages (IEN 83-08), but as noted above, it appears to be an isolated mechanical failure.

1.4 (Closed) Violation (387/84-11-01): HPCI Inoperable Above 150 psig Reactor Pressure

In February 1984, during a reactor startup, the inspector observed that the HPCI system was not in a standby readiness lineup although reactor pressure exceeded 150 psig. This was a violation of Technical Specification 3.0.4. A special inspection (50-387/84-11) was conducted and an enforcement conference held on March 20, 1984. The specific causes of the HPCI inoperability were: difficulty in placing the HPCI system in standby readiness lineup due to lineup problems; and operators not recognizing that HPCI was required to be operable before exceeding 150 psig in accordance with Technical Specification 3.0.4. Technical Specification 3.0.4 requires that entry into an Operational Condition or other specified condition not be made unless Limiting Conditions for Operation are satisfied. The root causes of this event were not performing complete system checkoff lists (HPCI topaz inverter not included) and lack of strict control of the startup during a shift turnover.

In response, the licensee added the HPCI topaz inverter to the system checkoff list and the operator rounds sheets. The General Operating Procedures for startup, GO-100-002 and GO-200-002, were revised to require a sign-off that RCIC and HPCI are operable prior to exceeding 150 psig. All operators were trained on the above event. The inspector verified that the above actions were completed.

1.5 (Closed) Unresolved Item (387/85-12-04): Nitrogen Inerting - SIL 402

In Inspection Report 50-387/85-28, the inspector reviewed the licensee's response to GE Service Information Letter SIL-402, concerning the potential for injecting cold nitrogen into the containment. As a result of licensee's evaluation of the nitrogen inerting and makeup systems, the licensee identified the need to install temperature instrumentation in the nitrogen makeup line.

In accordance with PMR 85-3126, the licensee installed a temperature indicator with an alarm setpoint of -5 degrees F. in the nitrogen makeup line in the Radwaste building. The alarm condition is annunciated in the control room. The inspector verified completion of the modification and that the operating procedures for Units 1 and 2 and alarm response procedure were revised to require terminating nitrogen makeup if the low temperature setpoint is reached.

1.6 (Closed) Unresolved Item (387/82-39-02): Loop Checks Didn't Include Computer Points

In 1982, the inspector determined that the licensee had no formal method of verifying that computer points used to verify technical specification surveillance requirements were calibrated. The licensee revised procedure IC-66-001, Instrument Loop Calibration Check procedure to include checking computer points when performing an instrument loop calibration.

1.7 (Open) Inspector Followup Item (387/84-22-05): Control of Bypasses

In July 1984, the inspector identified a number of deficiencies with the licensee's program for control of bypasses. Among the deficiencies were Operations not performing reviews of the bypass log every month to ensure that bypasses greater than 180 days old are dispositioned, work groups not providing written response to the Operations log review, and some bypasses were greater than 180 days old and had not been dispositioned.

The inspector audited the Unit 1 bypass log in December 1985 and noted the following discrepancies:

-- No monthly review of the Unit 1 log was apparently performed by Operations for the months of July and September 1985.

-- The only work group consistently providing responses to Operations log review of bypasses greater than 180 days old is the Technical Staff. Maintenance and I&C also had bypasses greater than 180 days during this period, but only one response was provided in the last 6 months from each of these work groups.

-- Procedure AD-QA-307, "Electrical and Mechanical Bypass Control", does not specifically require independent verification of bypasses as specified in ANSI N18.7, Section 5.2.6 and the Operational Quality Assurance manual.

The first two discrepancies are similar to those identified in July 1984. Licensee took action to address these areas, but the action was not sufficient to prevent the discrepancies from recurring.

With respect to the last discrepancy, concerning independent verification, the licensee had identified this deficiency and prepared a draft revision to AD-QA-307 to require independent verification of bypass installation and removal. The licensee agreed to finalize and issue a revised procedure on a priority basis.

During the review, the inspector noted that there are 64 bypasses on Unit 1 which are greater than 180 days old. On Unit 2, there are 39 bypasses greater than 180 days old. Many of these bypasses are on safety related systems. These bypasses involve changes to the plant that are not reflected in plant drawings. The bypasses have, in general, been dispositioned in accordance with AD-QA-307 and have been assigned a Plant Modification Request number, Request for Modification number, or other disposition method number. However, there has apparently not been emphasis on permanently implementing or removing the older bypasses. The inspector discussed this concern with the Operations Supervisor and Station Superintendent and will followup on licensee's corrective actions.

1.8 <u>(Closed) Inspector Followup Item (387/85-21-01): Discrepancies in Drawings and Procedures Related to the Standby Liquid Control System</u>

In July 1985, the inspector identified several procedural deficiencies related to the Standby Liquid Control System. The findings included incorrectly identified circuit breakers and incomplete check-off lists.

The inspector reviewed the revised operating procedure, alarm response procedure, and system check-off list and verified the discrepancies have been corrected.

1.9 <u>(Closed) Violation (388/84-22-01): Failure to Properly Perform a Surveillance Procedure and Return the RCIC System to its Automatic Start Alignment</u>

In May 1984, the inspector found the Unit 2 RCIC pump controller in manual following completion of surveillance testing. The system was not re-aligned for automatic start, as required by the surveillance procedure. In addition, several control panel walkdowns conducted during shift turnover failed to identify the mispositioned controller.

In response to the violation, surveillance procedures SO-150-003 and SO-250-003 were revised to include a verification signature for the step returning the RCIC pump controller to automatic. The original procedure did not require such a verification.

The Unit Supervisor and PCO perform a walkdown of control room panels following shift turnover as directed by administrative procedure AD-QA-303, "Shift Routine". The completion of the walkdown is recorded on the shift turnover list. The inspectors will continue to monitor the effectiveness of the control room panel walkdowns during the routine inspection program.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators were reviewed. Nuclear Instrument panels and other reactor protection systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator, and nuclear plant operator logs covering the entire inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period.

No unacceptable items were identified.

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, cable spreading rooms, penetration areas, reactor and turbine buildings, diesel generator building, ESSW pumphouse, and the plant perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

No unacceptable items were identified.

3.0 Summary of Operating Events

3.1 Unit 1

At 3:08 p.m., December 2, the Unit 1 reactor tripped from full power due to a turbine trip on high reactor vessel level. Two minutes later, the Unit 2 reactor tripped from 80% power on low vessel level (See below). This event initiated at 3:05 p.m. when Engineered Safeguards Service (ESS) transformer 111 deenergized causing a momentary loss of Unit 1 4KV bus 1C and Unit 2 4KV bus 2C. The busses were reenergized by another ESS transformer. The voltage transient during the transfer caused a loss of control signal to both units reactor feed pumps (RFPs) resulting in lock up of the controls at the pre-existing speeds. A slow level increase ensued on Unit 1 and the operators were unable to regain control of the RFPs before a high level trip occurred. Troubleshooting of ESS transformer 111 found a faulty "sudden pressure" switch which was repaired. The unit reached criticality at 10:00 p.m., December 4, and was at full power on December 8. (See Detail 3.3).

3.2 Unit 2

On November 27, 1985 at 2:25 a.m. the unit reduced power to 80% due to an apparent tube leak in the 5A feedwater heater. The feedwater string was isolated. Later investigations found a faulty level switch which caused an extraction steam isolation.

On December 2 at 3:10 p.m. the Unit 2 reactor tripped from 80% power on reactor vessel low level following a momentary loss of 4KV bus 2C. (See above). While the operators attempted to restore control of the RFP's, level decreased to the low level setpoint, causing the trip. MSIV's also closed due to the level transient. RCIC and HPCI were used for level and pressure control. The unit was shutdown to condition 4 to perform maintenance in the drywell. The unit returned to operation on December 7.

3.3 Units 1 and 2 Reactor Scram

At 3:05 p.m., December 2, ESS transformer 111 deenergized causing a momentary loss of offsite power to the Unit 1 1C and Unit 2 2C 4KV busses. These busses were reenergized by ESS tranformer 211. The momentary power interruption caused a loss of control signal to all Unit 1 and Unit 2 reactor feedpumps (RFPs), which receive control power from panels 1Y218 and 2Y218. The 'C' diesel generator also auto-started but did not load on the bus. The loss of control signal caused the RFPs to lockup at pre-existing speeds. The 'A' recirculation pump on both units began to runback and then the scoop tube locked resulting in a slight power decrease. The pre-existing feedwater flow was slightly greater than steam demand and a slow level increase occurred on both units. Unit 1 operators noticed

that all of the feed pump controllers transferred to manual. They attempted to control the 'C' RFP and return it to auto, but this had no effect on feed flow. The green 'A' and 'B' RFP control signal failure interlock lights did not energize.

The operator apparently did not attempt to reset the control signal failure interlock on any RFPs and hence, he had no feed control. Vessel level increased to the high level setpoint of +54 inches which caused a main turbine trip from full power with a resulting reactor scram on turbine control valve fast closure at 3:08 p.m. Two safety relief valves lifted to mitigate the initial pressure increase. RCIC auto started on low level, and HPCI was out-of-service for maintenance. Conditions were normal following the scram and the plant was quickly stabilized in hot shutdown.

On Unit 2, which was at 80% power, vessel level also began a slow increase. Unit 2 operators noticed that the 'A' RFP had a signal failure alarm in, but 'B' and 'C' did not. All RFP controllers automatically transferred to manual. The operators attempted to take manual control and returned the 'B' and 'C' pumps to automatic. The operator apparently reset the control signal failure interlock on the 'A' RFP which was still in manual, and pump speed rapidly decreased. The control signals for the 'B' and 'C' RFPs, which were in automatic, were also reset and they attempted to restore level, but were unable to prevent level decreasing. Level decreased to the low level setpoint of +13 inches, resulting in a reactor scram at 3:10 p.m. The void collapse due to the scram caused a further level drop to -32 inches. Main steam isolation valves (MSIVs) shut due to low level (nominal setpoint is -35 inches). The 'A' safety relief valve was manually used for pressure control. RCIC and HPCI were started to control level until they tripped on high level. They were later restarted with RCIC in the vessel injection mode for level control and the operators alternated between HPCI injection and full flow test for level and pressure control. The plant was stabilized in hot shutdown.

The inspectors reviewed GETARs traces, plant computer data, electrical schematics, and operator interview sheets and attended post-scram and PORC briefings to verify the cause of the event and ensure that equipment operated as designed.

The cause of the loss of ESS transformer 111 was due to a faulty sudden pressure switch. Transformer testing was conducted to verify that no transformer damage resulted. The faulty switch was replaced. The cause of the feedwater control signal lockup was due to the momentary loss of non-ESS electrical panels 1Y218 and 2Y218, which are normally powered from the 1C and 2C 4KV busses, respectively. Several previous reactor scrams have occurred due to electrical disturbances which caused momentary interruptions of power to 1Y218 or 2Y218. Specifically, the Unit 1 scrams which occurred on June 24,

1983, June 13, 1984 and July 3, 1984 were due to a loss of transformer T-10 which caused momentary power interruption to 1Y218. Following the July 3, 1984 scram, a modification was installed on Units 1 and 2 which provided an uninterruptible power supply (UPS) to portions of the recirculation pump circuitry which were powered by 1Y218 and 2Y218 (previously, in addition to locking up feedwater, the 'B' recirculation pump would runback causing a transient). A modification was prepared, but not installed at the time of the December 2 event, which would provide an UPS to the feedwater control circuitry presently powered by 1Y218 and 2Y218. This modification, PMR 85-3140 and 85-3141, has now been installed on both units.

Following replacement of the sudden pressure switch on ESS transformer 111, checking the switch on the other three transformers, installation of the UPS modification, and several other minor maintenance items, Unit 1 was returned to criticality at 10:00 p.m., December 4, 1985.

A contributor to the cause of the scrams were inoperable control signal failure lights on the RFPs. On Unit 1, the 'A' and 'B' RFP control signal failure lights did not come on, although all pumps lost their control signals. One light was determined to be burned out and the other had a loose socket connection. On Unit 2, the 'B' and 'C' RFP control signal lights also did not come on due to a burned out bulb and a loose socket. This condition misled the operators into thinking that the feedpump controllers were still controlling feedpump speed. The licensee is evaluating methods of checking bulbs that are not normally lit and there is a remaining open issue in the Detailed Control Room Design review concerning the lack of test capability for single indicator lights. This issue is under review by NRR.

With the exceptions noted above, the licensee's and inspector's review indicated that the units operated as designed and that the likelihood of another scram due to loss of an offsite source, is reduced by powering the feedpump controllers from UPS. However, loss of an offsite source could still cause problems with condenser vacuum due to recombiner loss. The licensee is planning on making additional power supply modifications in the long term to correct these problems.

4.0 Licensee Reports

4.1 In-Office Review of Licensee Event Reports

The inspector reviewed LERs submitted to the NRC:RI office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was

required from the licensee, whether generic implications were involved, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1

*85-030-00, Reactor Scram Due to Blown RPS Fuse During Surveillance Testing

*85-031-00, Turbine Trip/Reactor Scram on Moisture Separator 'B' Drain Tank High Level

*85-032-00, Reactor Water Cleanup System Spills and Isolations

85-033-00, Noble Gas Sample Obtained Late Due to Technician Error

Unit 2

None this period.

*Previously discussed in Inspection Report 50-387/85-31; 50-388/85-26.

4.2 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that the report included the required information; that test results and/or supporting information were consistent with design predictions and performance specifications; that planned corrective action was adequate for resolution of identified problems, and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special reports were reviewed:

-- Monthly Operating Report - October 1985, dated November 12, 1985

-- Monthly Operating Report - November 1985, dated December 9, 1985

The above reports were found acceptable.

5.0 Monthly Surveillance and Maintenance Observation

5.1 Maintenance Activities

The inspector observed portions of selected maintenance activities to determine that: the work was conducted in accordance with

approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and QC hold points were established where required; functional testing was performed prior to declaring the particular component operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

Activities observed included:

-- 'A' Diesel Generator 1L cylinder head replacement performed on December 13, 1985 under WA S55997.

No unacceptable conditions were noted.

5.2 Emergency Diesel Generator Surveillances

The inspector conducted a review of selected emergency diesel generator (EDG) surveillance procedures to ascertain whether the surveillance of safety-related systems and components is being conducted in accordance with approved procedures as required by Technical Specifications.

5.2.1 18 Month EDG Inspections

Technical Specification Surveillance Requirement 4.6.1.1.2.d.1 states that at least once per 18 months, each of the diesel generators shall be demonstrated operable by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations. Section 15 of the Cooper-Bessemer Operating and Maintenance Manual provides the manufacturer's recommendations for periodic reliability checking and maintenance inspections. Surveillance procedure SM-024-002, Revision 0, "18 Month Emergency Diesel Inspection", provides an outline of the steps necessary to fulfill the 18 Month EDG mechanical inspection and surveillance procedure SM-024-A01, Revision 1, "Diesel Generator 'A' 18 Month Inspection" provides the steps required to perform the 18 Month electrical inspection of the 'A' EDG.

Based on review of the above procedures, the following maintenance inspection items recommended by the vendor manual are not currently included in the surveillance procedures:

-- Check bearing temperatures for excessive heat 15 minutes after the four hour loaded run.

-- Check vibration damper on the auxiliary drive for dents and mounting.

-- Check the main drive for idler gear endplay and bearing for wear.

-- Using the engine analyzer to record pressure/time and vibration diagrams for each power cylinder immediately following the annual inspection.

-- Clean lubricating oil and jacket water coolers and check for leaks. (Every five years)

  Note: The cleaning of the lubricating oil and jacket water coolers is included in the preventive maintenance program for every two years.

-- Inspect all crankcase core plugs in main frame for tightness.

-- Remove cylinder heads and check condition of main valve seats and reseat all valves if required. Replace all head gaskets and O-ring seals. (Every five years)

In addition to the above inspection items, the vendor also recommends checking the operation and calibration of all control and safety shutdown devices and inspecting the air tubing. Although not included in the above approved surveillance procedures, these checks are performed by I&C under the preventive maintenance program every two years. The vendor recommends performance of this maintenance every year. The preventive maintenance program performs several of the recommended items, but approved procedures are not required and PM's are allowed to be waived and do not have the same controls as the surveillance program.

In December 1981 (pre-licensing), a Nuclear Quality Assurance (NQA) Audit identified that the maintenance procedures did not include the vendor recommendation for head removal and valve reseating during the five year inspection (Finding 0-81-08-01). In response to the finding, surveillance procedure SM-24-002, Revision 2 was issued which included an option of either removing the cylinder head or inserting a boroscope to visually inspect each power cylinder. Later procedure revisions deleted the head removal option, and hence, only a boroscope

inspection is specified during the 18 month inspections. In response to the audit finding the plant staff also stated that the procedures were prepared and implemented during the preoperational test program with technical service representatives from Cooper-Bessemer. These procedures, though, have gone through several revisions and several of the requirements have been deleted in the process.

Technical Specification 6.8.1 states that written procedures shall be established, implemented and maintained covering surveillance and test activities of safety-related equipment. Based on the above review, all of the manufacturer's written recommendations have not been included in the applicable surveillance procedures.

Since the surveillance requirement states that the procedures are to be prepared "in conjunction" with the manufacturer's recommendation, the licensee should be able to demonstrate that the omission of the vendor's recommendations are technically justified and concurred with by the vendor or the recommendations should be included in the approved surveillance procedures.

This item is considered unresolved pending review of the licensee's technical justification for omission of the vendor recommendations. (387/85-35-01)

5.2.2 Other 18 Month EDG Surveillances

During a review of other 18 month EDG surveillances, the inspector noted the following discrepancies:

a) Unit 1 and 2 Technical Specifications (TS) 4.8.1.1.2.d.3, 4.8.1.1.2.d.4.b, and 4.8.1.1.2.d.5 require various EDG tests that include voltage and frequency limits. The nominal limits are 4160 volts plus/minus 400 volts, and 60 plus/minus 3 Hz. There is an inconsistency between the Unit 1 and 2 Technical Specifications on the implementation of these limits. For the identical tests, the Unit 1 Technical Specifications specify limits of 4160 plus/minus 200 volts and 60 plus/minus .5 Hz. All of the surveillance procedures use the 4160 plus/minus 400 and 60 plus/minus 3 limits as the acceptance criteria. The inspector discussed this with NRR who indicated that the correct criteria is 4160 plus/minus 400 volts and 60 plus/minus 3 Hz. Thus, an administrative change to correct the Unit 1 Technical Specifications is needed.

b) Technical Specification 4.8.1.1.2.d.6(c) requires verification that all auto trips except lube oil pressure, generator differential and overspeed are bypassed upon loss of voltage on the emergency bus concurrent with a LOCA. Procedures SO-224-107/207 implement this test by the operators depressing the emergency stop pushbutton when the EDG is running in emergency, and verifying that the EDG does not trip.

The emergency stop pushbutton actuates the same relay as the non-emergency trips, but actuation of the individual trips or verification that the relay is actuated, is not performed. Procedures SO-224-107/207 are being revised before the next scheduled test, and the licensee agreed to revise the procedures to correct this deficiency.

c) Technical Specification 4.8.1.1.2.d.4(a) requires verification of bus deenergization and load shedding on a loss of offsite power (LOOP) signal by itself. Technical Specification 4.8.1.1.2.d.6(a) requires verification of bus deenergization and load shedding on a LOOP combined with a LOCA signal. Procedures SE-124-107/207 are used to implement both of these requirements but it only performs the latter, i.e. verification on a LOOP/LOCA signal. During performance of SE-124-A02, B02, C02, D02, which are the LOOP tests for Unit 1, procedure step 6.3.8 requires "observation" that the bus deenergizes and load sheds on a LOOP, but it is not part of the acceptance criteria and does not include a verification.

The inspector will review the licensee's corrective action on the above discrepancies. (387/85-35-02; 388/85-31-01)

6.0 Exit Meeting

On December 19, 1985 the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.